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German FGD/De-NOx (Flue Gas Desulfurization/Denitrification) Experience

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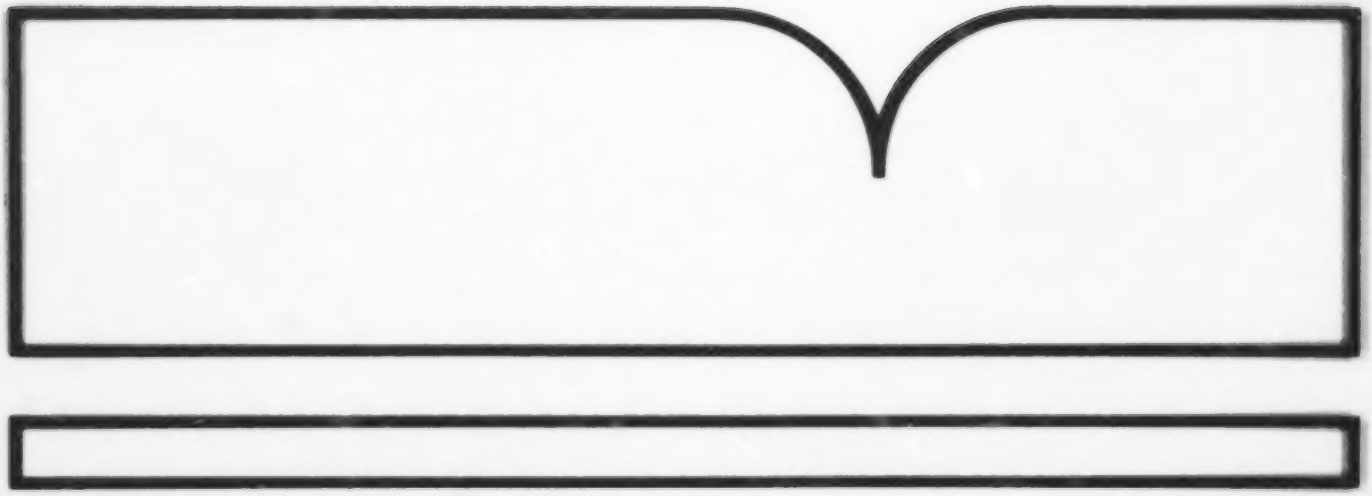

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16. ABSTRACT

The paper gives detailed details of major flue gas desulfurization (FGD) and denitrification (de-NO installations in West Germany for coal-fired boilers. The status of technology in European countries is also presented. The paper provides an understanding of principal types of control system designs that have been applied, outlines technological advancements that have been achieved, and reviews operating experience gained to date in expanded use of FGD and NOx removal facilities in Europe in the 1980s. It describes significant differences between FGD service and practice in the U.S. and Japan, and gives specific information that may help improve operation and reliability of new and retrofit FGD installations in the U.S. Principal topics include overviews of: (1) government emission control requirements in Europe for new and existing coal-fired sources; (2) West German FGD and de-NOx installations and purchase commitments, including details of generic processes applied, operating history, current performance, and trends and developments in technology utilization; (3) control of industrial boilers; (4) management of solid and liquid waste by-products; and (5) sunstantial activities in other European countries.

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ABSTRACT

Updated details are presented of major flue gas desulfurization (FGD) and denitrification (de-NO_x) installations in West Germany for coal-fired boilers. The status of technology in other European countries is also presented. The purposes of the paper are to provide an understanding of the principal types of control system designs that have been applied, to outline technological advancements that have been achieved, and to review operating experience gained to date in expanded use of FGD and NO_x removal facilities in Europe in the 1980's. Significant difference from FGD service and practice in the U.S. and Japan is described, and specific information that may serve to help improve operation and reliability of new and retrofit FGD installations in the U.S. is offered. Principal topics include:

- o A presentation of governmental emission control requirements in Europe for new as well as existing coal-fired sources.
- o An overview of West German FGD and de-NO_x installations and purchase commitments including details of generic processes applied, operating history and current performance, and trends and developments in technology utilization.
- o Control of industrial boilers.
- o Management of solid and liquid waste by-products.
- o Substantial activities in other European countries.

WEST GERMAN SO_2 REGULATIONS

Recent acceleration of European activities for reduction of SO_2 and NO_x emissions is centered in the Federal Republic of Germany (West Germany). Great emphasis has been placed on extensive forest damage, considered to be tied to air pollution, which has occurred in some regions of the country. Effects on trees have been particularly severe in the area of North Rhine-Westphalia in the central portion of the country, as well as Baden-Wuerttemberg in the southwest. In 1983 West Germany enacted a major national acid rain control directive (1) for SO_2 (per Table I), spawning a major program of FGD installation at both new and existing boilers, primarily on large coal-fired units. Note that boilers larger than 110 MW(e) have been required to add stack gas cleaning by 1988. Reduction of emissions from smaller boilers, 18 to 110 MW(e), is tied to a 1993 deadline. Requirements are the same for existing oil-fired boilers.

Note also that, in addition to an absolute limit on the rate of SO_2 emission, a minimum percent removal is specified for boilers 35 MW(e) and larger, thus preventing the use of fuel switching to achieve control compliance. The provisions for fluidized bed boilers in the range of 35 to 110 MW(e) require that SO_2 emission reduction be 75% (rather than 60%). Informed opinion in West Germany suggests that the 400 mg SO_2/Nm^3 (144 ppm) requirement for boilers above 110 MW(e) may well be lowered to around 200 mg (72 ppm) by 1990 or before. Similarly, the 60% removal requirements for 35 to 110 MW(e) boilers may be increased in the next several years.

After declaration of individual boiler owners by July 1, 1984, any existing larger than 110 MW(e), if committed to being decommissioned by April 1, 1993, are permitted to operate for no more than 30,000 additional hours at an SO_2 emission rate not to exceed 2,500 mg/Nm^3 (900 ppm).

Additionally, the 1983 law requires that flue gases in the stack following desulfurization must typically have a minimum temperature of 72°C (162°F) as they exit the stack.

Surveillance by continuous monitoring and recording of stack SO_2 emissions are required for coal- and oil-fired boilers larger than 18 MW(e). Compliance requires that (2) all daily mean values are equal to or smaller than the emission limit value; 97% of half-hour mean values are equal to or smaller than 1.2 times the emission limit value; and all half-hour mean values are equal to or smaller than twice the emission limit value.

Emission limits for small existing industrial boilers [e.g., 1% sulfur fuel fired units larger than approximately 6,500 lb/hr steam generation, the equivalent of approximately 0.5 MW(e)], are addressed in new national legislation (TA Luft) of February 27, 1986 (3). With many exceptions at the present time, it is specified that boilers emitting more than 5 kg SO_2/hr must limit emissions to 500 mg/Nm^3 (180 ppm).

Individual local (provincial) governments have the authority to impose more stringent requirements than those specified by the national laws. For example, (4) in North Rhine-Westphalia (with nearly 50% of the electric power generation of the entire country, a large portion being fired with lignite), special requirements were placed on approximately 3,000 MW(e) of existing lignite fired boiler capacity in 1984 calling for an interim SO_2 emission reduction of 110,000 metric tons per year by 1987 (through temporary low-capital-cost dry-alkali injection means).

FGD UTILIZATION

Table II shows the number and size of existing West German boilers, almost all firing low-medium sulfur fuel, generally bituminous coal or lignite, and indicates that more than 150 units are impacted by the 1988-deadlined SO_2-control requirements (5). Also affected are 7,400 MW(e) of new, coal-burning units (6) under construction or expected to start up by approximately 1990.

Furnaces larger than 110 MW(e) are almost exclusively fired with hard (bituminous) coal or lignite. The sulfur content of the hard coal is about 0.7-1.2% (in the future up to 1.5%), with ballast coal containing as high as 2.7% sulfur; of wet raw lignite, 0.3-1.2%.

In keeping with the 1988 target compliance-date almost all utility units are now being retrofitted with scrubbers except for approximately 12,000 MW(e) of capacity to be retired by 1993 after no more than 30,000 additional hours of operation. More than 100 FGD installations, primarily commercial-gypsum-producing types comprising more than 35,000 MW(e), are being erected. Approximately 50,000 MW(e) of FGD is expected to be in place by the early 1990's (7). FGD facilities already running are the result of a comparatively modest, provincial control program that began prior to 1983 and resulted in 20 FGD applications, almost all for slipstream single-module installations. Comparatively few boilers under 110 MW(e) have been retrofitted with FGD to date. In the absence of a percent removal stipulation in the 1983 law, boilers smaller than 35 MW(e) may be expected to typically rely on fuel modifications/switching as needed to meet the specified 2,000 mg/Nm^3 (720 ppm) SO_2 emission limit. Influenced by the new control activity in Germany, approximately 2000 MW(e) of usable-gypsum-producing FGD systems are being installed in The Netherlands, and a major FGD installation program is underway in Austria on utility boilers.

In West Germany, SO_2 emissions of 4 million metric tons per year, a pproximately 80% of which originate from utility and industrial boilers, are expected to be reduced by almost two thirds by 1988. The cost for these FGD installations has been projected to be as much as 15 billion German marks (DM).

PRINCIPAL FGD TECHNOLOGY USED

Table III illustrates the manner in which the very large lime/limestone FGD market (approximately 93% of all capacity sold to date) has been shared by the six principal system suppliers, using a mix of Japanese, U.S., and German technologies (6). FGD selection in Germany has reflected a strong emphasis on the need to achieve high system availability (95%). As in Japan, most of the installations of each principal supplier are designed to employ forced oxidation to yield a commercially usable gypsum and to thus avoid the substantial cost and complexity of alternative throwaway-waste management in Europe.

However, 30 throwaway-waste FGD systems of 9000 MW(e) capacity are being installed, all at minemouth lignite-fired plants where disposal of solid waste in the mine is anticipated. In mainland Europe the use of throwaway-solid-waste processes, including dry or semi-dry scrubbing methods feasible for low-sulfur fuel applications in Scandinavia and the U.S., is curtailed by the present lack of effective means of utilizing sulfite-containing FGD waste and of adequate landfill disposal space.

Gypsum-solids dewatering systems are comparatively simple, typically comprising primary dewatering by liquid cyclones, with final dewatering by centrifuge or horizontal vacuum filter. Due to transportation-economics some early installations in Germany use lime in lieu of limestone. However, as a universal energy conservation measure, all recent FGD commitments have been dedicated to the use of limestone reagent. Rotary regenerative heat exchangers are being commonly used for the purpose of meeting the mandatory 72°C (162°F) minimum stack temperature requirement without use of augmental energy supply for gas reheat.

Much like a frequent process design practice in the U.S. during the 1980's, the most typical FGD system arrangement that is currently being applied in Europe incorporates the following features:

- o Lime or limestone reagent use, preferably limestone.
- o Spray tower absorber design, rubber-lined.
- o In-situ forced oxidation facilities installed in the sump of the absorber without use of sulfuric acid reagent for pH adjustment.
- o Production of a throwaway or usable grade of gypsum.
- o Single-loop systems that omit low-pH pre-scrubbing used extensively in Japan and in some early German installations for segregated removal of hydrogen chloride and other minor raw-gas components.

Descriptions of the most common FGD installations of the principal lime/limestone scrubbing system suppliers follow.

DEUTSCHE BABCOCK

This most frequently applied FGD process uses a single- or two-stage limestone spray tower followed by post-reaction with forced oxidation in the sump (8). In an initial installation, magnesia additive enhances SO_2 absorption and internal scale control, and pH control in the forced oxidation step is achieved with sulfuric acid reagent feed. Subsequent installations instead achieve forced oxidation at the low pH in the post-precipitation section at the bottom of the absorber.

MITSUBISHI/THYSSEN

In the conservative design of Mitsubishi, which is the largest FGD system supplier in Japan, individual wet process loops are used for gas quenching (chloride removal) and for grid-packed-tower SO_2 absorption. Earliest German installations are ex-situ forced oxidation with pH adjustment by sulfuric acid. All recent German systems being supplied use in-situ forced oxidation in the SO_2 absorber sump without use of sulfuric acid reagent feed (9).

CHEMICO-MITSUI/STEINMUELLER (GEESI)

Initial installations have included Chemico (GEESI) spray-tower absorbers and use of the Mitsui ex-situ forced-oxidation system from Japan using an oxidation catalyst and sulfuric acid. Subsequent installations in Germany have incorporated the oxidation step in the bottom of the absorber tower (as in the case of applications of the process in the U.S.), and this in-situ design eliminates the use of a catalyst and sulfuric acid (10).

RESEARCH COTTRELL DOUBLE-LOOP

Research Cottrell's familiar double-loop in-situ limestone scrubbing process extensively used in Germany has been the most common forced-oxidation FGD process applied in the U.S., and accounts for most usable-gypsum producing FGD installations in operation or under construction here. With large scale use of by-product gypsum in Germany for plaster/mortar products that tolerate elevated chloride levels, some Research Cottrell installations include provision for advantageous drying of the cake product by direct contact with a portion of the scrubber inlet-gas stream (11).

SAARBERG-HOELTER-LURGI BUFFERED LIMESTONE

In a unique limestone slurry scrubbing process that uses a combined co-current/counter-current absorber design, SHL utilizes organic (formic) acid buffering in conjunction with in-situ forced oxidation (12). Saarberg-Hoelter no longer markets its earliest process design, which used lime reagent and recirculated a high-chloride-level clear liquor supplied by thickener overflow. In at least one installation this supplier is using

the plant cooling tower structure in lieu of a flue-gas stack to discharge the FGD outlet gas, an exhaust arrangement that the acid rain legislation exempts from the 72°C (162°F) minimum stack-exit-temperature requirement.

BISCHOFF SINGLE-LOOP

German supplier, Gottfried Bischoff, with a substantial commercial background in supply of large-capacity wet-scrubbers for the iron and steel industry in the 1960's, has installed a number of comparatively simple, single-module, approximately 200 ft high by 40 ft diameter, lime/limestone FGD spray towers of over 400 MW(e) capacity designed with in-situ forced oxidation in the sump. An early installation on the North Sea uses seawater for FGD makeup water; yet, by adequate by-product classification and fresh-water washing, achieves a gypsum yield used for commercial-scale wallboard manufacture (13).

OTHER FGD PROCESSES

A number of regenerative and throwaway-waste processes are being applied in Germany.

WELLMAN LORD

The familiar Wellman Lord process using clear sodium sulfite liquor scrubbing has been applied in approximately five plants of approximately 200 MW(e) aggregate capacity, primarily for elemental sulfur by-products yield (6).

WALTHER AMMONIA

In four installations aggregating 750 MW(e) the Walther Process uses ammonia scrubbing to produce ammonium sulfate by-product liquor that is converted to a dry fertilizer product in a small auxiliary spray-dryer system. One of the installations of 70 MW(e) capacity is designed for removal of NO_x in a second ammonia scrubbing stage, operating in an absorption/oxidation mode, but it is understood that this wet NO_x removal technique may be abandoned (3).

ACTIVATED CARBON

A 237 MW(e) Bergbau-Forschung/Uhde installation will use activated carbon (coke) at 120°C (250°F) in a moving-bed adsorber system for SO_2 removal, with high-temperature coke regeneration in a desorber, which produces a rich-SO_2 offgas that will be converted into commercial sulfuric acid (14). The system uses ammonia reagent to also collect NO_x at high efficiency. A closed conveyor system cycles the coke between the adsorber and the desorber.

SAARBERG-HOELTER-LURGI SIMULTANEOUS WET SO_2/NO_x SCRUBBING

A 750 MW(e) Saarberg-Hoelter-Lurgi usable-gypsum-producing lime scrubbing installation is designed to use a ferrous-based EDTA chelate to gain simultaneous high-efficiency SO_2 and NO_x removal in a wet absorption/reduction mode (15). The process (16) is based on the principle of catalytic reduction of NO (nitric oxide) by SO_2 in the form of sulfite ions, forming mainly elemental nitrogen and sulfate. Chemical reducing conditions in the scrubbing medium are essential in order to retain the solved iron in the catalytically active, bivalent form. A slipstream of the scrubber liquor is drawn from the absorber, reactivated by high-efficiency precipitation with slaked lime, and returned to the scrubber. The precipitate, which contains a large amount of calcium sulfite, is dewatered, suspended or solved in sulfuric acid, and oxidized with air to form the gypsum by-product. Minor production of unique tramp sulfur/nitrogen and sulfur compounds (formed in the catalyzed chemically reducing environment of the scrubbing medium) is purged by crystallization from a blowdown stream followed by calcination to form recyclable/disposable chemical forms.

DRY SCRUBBING

A number of small boilers aggregating over 300 MW(e) are being equipped with throwaway-waste dry scrubbing systems using spray dryers. In instances where suitable solid waste management schemes are available, this technique may be expected to be applied to additional existing boilers 110 MW(e) and smaller in meeting the 1993 deadline for 60% SO_2 removal.

CIRCULATING-FLUID-BED SCRUBBER

This hydrated-lime-using dry-scrubbing system of Lurgi Corporation, designed to operate upstream of the electrostatic precipitator, is unique because of the unusually high coal sulfur levels at which it is being applied (17). A 50 MW(e) installation that began operation in 1984 removes 95% SO_2 from a flue gas from lignite firing containing 4,250 mg SO_2/Nm^3 (1500 ppm), and a 125 MW(e) installation under construction is designed for 97% SO_2 removal in a low-grade lignite service with inlet flue gas containing 13,000 mg SO_2/Nm^3 (4700 ppm). The operating system achieves 95% availability and lime/sulfur stoichiometric ratio of 1.7 with the outlet gas temperature at a -2.8°C (27°F) approach to the wet bulb temperature. In an upward-flow dry/semi-dry reactor, inlet flue gas fed via an extended venturi nozzle is mixed with a finely pulverized hydrated lime and injected water. A relatively high flue-gas velocity of between 2 and 7.9 m/sec (6.5 and 26 ft/sec) carries unreacted lime and reaction products out of the top of the reactor. Later, solids are separated from the flue gas in the downstream particulate collector, typically a combination mechanical collector and electrostatic precipitator, and a portion of it is recirculated to the reactor to significantly increase solids residence time and utilization.

LIME/LIMESTONE INJECTION INTO A MULTISTAGE BURNER (LIMB)

Principal worldwide application of LIMB to date is in lignite fired boilers in West Germany, where approximately 3000 MW(e) of existing lignite fired capacity will be retrofitted for temporary SO_2-emission-reduction duty in North Rhine-Westphalia by 1987 (4).

Significant precipitator fouling problems and poor SO_2 removal efficiency are reported for a full-scale 700 MW(e) test in Germany in bituminous coal fired service using limestone fed near the burners (18). In full scale tests at 125 MW(e) at another bituminous coal boiler in Germany, limestone and hydrated lime reagent were fed alternately near the boiler-furnace outlet. With 2 moles of sorbent feed per mole of inlet SO_2, removal efficiency was 32% with limestone and 44% with hydrated lime. Somewhat poorer results were achieved in limestone injection tests in a pulverized bituminous coal fired boiler in Malmo, Sweden. In short-term furnace injection tests in a small bituminous coal fired unit in Germany similar low removal efficiencies were measured (19).

In Finland a new 250 MW limestone injection system, with a May 1986 startup (20), gains only 30% removal in the furnace but incorporates a tail-end activation reactor (simplified spray-dryer contactor) to humidify the flue gas upstream of the electrostatic precipitator to gain an overall SO_2 efficiency of approximately 60% to over 80% with flue-gas-temperature approach to the wet bulb temperature from 2°C to -12.8°C (36°F to 9°F), respectively. The unit is in peaking service firing bituminous coal.

FGD SYSTEM EXPERIENCE

Use of FGD in the Federal Republic of Germany (West Germany) is comparatively recent but, as of the end of 1984, almost 3000 MW(e) of lime/limestone scrubbing systems were in operation, all of single-module slipstream design to meet requirements of pre-1983 legislation. These FGD system installations are reported to have provided acceptable reliability and performance. However, German electric utility specialists note that, with only partial scrubbing of plant flue gas, these earliest installations have not been subjected to typical full-scale electric-utility-industry operating conditions requiring high availability at sustained high/variable load. Additional FGD capacity of approximately 5000 MW(e) originating from the 1983 legislation has now come on line, but is in an initial stage of operation without an extensive period of experience. Thus, Germany's massive FGD program is seen to be at too early a stage of implementation to show broadly demonstrated success or to thoroughly characterize performance and reliability of system designs that are being applied.

Based on extensive economic assessments recently published (21) retrofit capital investment for a typical 350 MW(e) limestone scrubbing FGD installation is reported to be 80 million DM; i.e., 230 DM/kW.

Annual cost with 6000 hr/yr of operation is 19.3 million DM including fixed cost of 14.8 million DM (representing 18.5% of the capital investment of 80 million DM). On a unit basis this annual cost equals 0.92 pfennig (Pfg)/kWh. Values are based on 1985 currency.*

Operating with characteristically low or moderate coal sulfur level, and applying commercially demonstrated and conservatively designed forced-oxidation systems, no critical technical problems have been experienced or forecast at the present time. Because of comparatively low coal sulfur level, availability concerns have not required the use of spare scrubbing modules. Similarly, the low rate of limestone consumption in low-sulfur service, and the logistics of supply in Germany have resulted in the practice of purchase of limestone in ground form, eliminating the need for limestone grinding facilities at the power plant. Feasibility of flue-gas reheat using rotary regenerative heat exchangers has been effectively demonstrated. FGD retrofitting has not presented insurmountable problems. However, great attention is being given to marketing as much as 5 million metric tons/yr of anticipated FGD gypsum production. New technologies are developed and are being promoted for reprocessing some of the by-product to anhydrite and alpha hemihydrate forms so as to supply available markets beyond those for normal gypsum alone (22). Through wastewater purge treatment carried out in the presence of gypsum precipitation from $CaSO_4$-supersaturated liquid, very low trace metal concentrations are achieved prior to outfall discharge (15). Unlike Japan, where common production of usable FGD gypsum in lieu of throwaway solid waste also requires a purge of FGD process liquor, German boilers are typically inland on fresh water streams and do not have seawater receiving-bodies to which to discharge FGD chloride-liquor blowdown from usable-gypsum-producing FGD operation. Due to the significant potential impact of the chloride blowdown on some German rivers a major policy decision by the national government has been pending on acceptable long-term FGD-chloride-waste management.

MATERIALS OF CONSTRUCTION

Except for Research Cottrell installations, which emphasize use of stainless steel construction, materials of construction in German lime/limestone FGD installations are typically (23):

Scrubbers

- Casing	Mild steel, rubber lined
- Flue gas inlet	Refractory lined
- Spray nozzles	Stainless steel, ceramic, and silicon carbide

*Based on 1 DM = U.S. $0.50, 1 Pfg per kWh = 5 mills per kWh.

- Oxidizer air distribution	Stainless steel and plastic
- Mist separator profiles	Polypropylene
Casing	Mild steel, rubber lined
Washing nozzles	Polypropylene
Tanks, Vessels	
- Large	Mild steel, rubber lined
- Small	Plastic
Regenerative Flue Gas Reheat	
- Rotary heat exchanger	
Raw gas connections, hot	Mild steel, flake glass lined
cold	Mild steel, rubber lined
Clean gas connections	Mild steel, rubber lined
Casing	Corten steel
Rotor structure	Corten steel
Heat storage, cold side	Plastic
Heat storage, hot side	Enameled steel
- Tubular type	
Casing	Mild steel, flake glass lined
Tubes, hot side	Mild steel
Tubes, cold side	PTFE or PVDF
Flue Gas Ducts	
- Ducts, dry and hot	Mild steel
wet	Mild steel, rubber lined, and flake glass lined
- Dampers, casing, dry	Mild steel
wet	Mild steel, rubber lined
- Disks	Mild steel; mild steel, rubber lined; and stainless steel
- Expansion joints	Fabric with PTFE foil, and Viton
Mechanical Equipment	
- Flue gas fan, dry	Mild steel
- Flue gas fan, wet	
Impeller	Stainless steel
Other parts	Mild steel, rubber lined

- Pumps	Stainless steel
- Agitators	Mild steel, rubber lined
- Hydrocyclones	
Feeding system	Mild steel, rubber lined
Cyclone	Porcelain and polyurethane
- Vacuum belt filter	
Frame	Mild steel
Drum, etc.	Mild steel, rubber lined
Filter cloth	Fabric with natural rubber
Vessels	Mild steel, rubber lined; GRP; and polypropylene

Pipeline and Accessories

- Pipes and valves	Mild steel, rubber lined; GRP; and polypropylene
- Butterfly valves	
Casing	Mild steel, rubber lined
Disks	Stainless steel, Hastelloy, and mild steel, rubber lined

FLUE GAS REHEAT

Inline reheating of water-saturated flue gas in the amount of 10°C (50°F), the approximate minimum increment needed to meet the 72°C (162°F) minimum stack exit temperature requirement in Germany, represents 1.6% of boiler heat input for a large power plant unit. Energy economics in that country for high-capacityfactor operation has provided strong motivation for commercial application of regenerative reheat means. Rotary air heaters, similar to those commonly used for regenerative combustion-air preheating in large boilers, have been extensively used for this purpose with more than 40 purchased and more than 14 already in commercial operation (24). Reliable operation of these heat exchangers has been tied to application of suitable materials of construction, good continuous performance of electrostatic precipitators dedusting the hot inlet gas, and use of high-efficiency horizontal-gas-flow mist eliminators limiting carryover of FGD scrubbing slurry. On-line, intermittent, high-pressure water washing has effectively prevented exchanger gas pressure drop (the sum of pressure drop across both sides) from exceeding a nominal 125% of the design value for clean conditions. Due to the inherent design of the rotary exchanger, 3-5% of design gas flow leaks from the high pressure side to the low pressure side. When, typically, the FGD booster fan is positioned on the hot dirty-gas side, SO_2 removal decreases substantially. However, a low leakage design has been developed for this system arrangement that has commercially demonstrated a leakage rate of no more than 0.5% (25).

A comparatively simple, tubular-heat-exchanger type, regenerative reheat system requiring no added flue gas ductwork is also gaining commercial use in Germany after long-term field testing in a lignite FGD installation. Tubes exposed to scrubbed gas are non-metallic, and circulating water is the heat transfer medium. Four such systems with an aggregate FGD capacity of 1,200 MW(e) are currently being installed (13).

In one case in Germany the wet FGD system is inside a hyperbolic cooling tower serving the power plant, the FGD outlet intermixing with a stream of air flow 25 times greater. Because of good dispersion gained through discharge of this substantial air flow the FGD system is exempted from normal FGD stack exit temperature regulations. For corrosion control a double coating of epoxy is applied to the internal surface of the concrete shell of the cooling tower. The capital cost is reported to be only 20% of that which would otherwise be required for a conventional flue-gas stack, and only 10% of that which would otherwise be also required for a rotary heat exchanger system for regenerative reheat.

FGD WASTEWATER MANAGEMENT

The application of usable by-product-forming, wet FGD systems, common in Germany, results in a significant discharge of brackish/saline wastewater. With typically high chloride levels (0.1 to 0.2%) in German bituminous coal, FGD waste-water management is a substantial problem. When discharge to receiving streams is not completely prohibited, the rate (26) of FGD liquor outfall is usually limited to the equivalent of 0.0158 m^3/sec (25 U.S. gpm) per 100 MW(e). When such saline liquor discharge is allowed, trace metal concentrations, dissolved sulfate, and suspended solids must be reduced to specified levels. A typical wastewater treatment system to accomplish this employing hydroxide precipitation may include two stages of neutralization, flocculation and sedimentation, the first stage operating at pH 9-10 to remove components such as cadmium and manganese, and the second stage operating at a pH of 8.5 to remove other components such as zinc and aluminum. An additive in the form of an organic sulfur compound serves as a special precipitation agent to remove mercury. A sludge dewatering facility is also needed.

FGD BY-PRODUCT GYPSUM MANAGEMENT

Commercially usable FGD gypsum production is expected to reach 2.5 million metric tons annually by 1988 and a substantially higher level by 1993. New process developments to convert substantial amounts of FGD solids by-product to anhydrite (anhydrous) and unique alpha hemihydrate forms are expected to help ensure fullest utilization of FGD by-product (22). Commercial technology is now available to build plants to process 100,000 metric tons per year of FGD gypsum yielding alpha hemihydrate at a cost of only 50 DM per metric ton (27). Table IV shows that ultimate commercial use of over 5 million metric tons annually is foreseen in West Germany.

LARGE INDUSTRIAL BOILERS

The many hundreds of West German boilers in the size range, 35 to 110 MW(e), that will require SO_2 removal in the amount of 60% or possibly substantially higher by 1993 represent a very large ongoing sales market rivaling the magnitude under the 1988 deadline. If implied assurances of an adequate gypsum market are believed and accepted, and particularly if control requirements are modified to call for SO_2 removal efficiency substantial higher than 60%, substantial use of gypsum-producing limestone scrubbing systems will result. If newer wet scrubbing technologies that can competitively generate more valuable and attractive by-products become commercially available, many applications would be expected. Proponents of economical dry and semi-dry SO_2 removal processes or use in this market appear to face substantial uncertainties in view of possible major difficulties in solid waste management and, in some instances, due to characteristically large fluctuations in boiler load and fuel characteristics (28).

OTHER COUNTRIES (23)

The Netherlands

Under Dutch law FGD with 90% SO_2 removal is required for all coal fired boilers larger than 300 MW(e). Ten FGD systems comprising approximately 2,400 MW(e) at four power plants are under construction, all designed for usable gypsum production. A new broader acid rain control law modeled after current West German legislation is expected to be passed in 1986.

Belgium

Although specific national laws requiring FGD do not presently exist, it is expected that a planned 600 MW(e) coal-fired boiler and an existing 300 MW(e) boiler being converted from blast furnace gas to coal will be required to have FGD at efficiency levels comparable to systems in West Germany.

Sweden

SO_2 emissions from boilers are limited to 300 mg/Nm^3 (108 ppm). A number of spray-dryer dry scrubbing systems are under construction.

Denmark

Regulations similar to those in West Germany for large power plants are developing.

Austria

A number of FGD systems of 80-90% removal efficiency are under construction. National requirements are being tightened to require 90% SO_2 removal for all new oil- and coal-fired boilers, and a maximum SO_2 emission of 300 mg/Nm^3 (108 ppm) for existing bituminous-coal-fired utility boilers and 400 mg/Nm^3 (144 ppm) for existing lignite-fired utility boilers (29).

Switzerland

National SO_2 regulations are similar to those in West Germany, but there are no existing coal- or oil-fired boilers of substantial size.

Italy

The government-owned national power company is building 10 MW(e) Wellman Lord, limestone-gypsum, and ammonia-scrubbing demonstration FGD systems in Sardinia for service with high-sulfur bituminous coal.

Other

Planning of FGD systems on very large SO_2 emission sources in the German Democratic Republic (East Germany) and Czechoslovakia has begun.

England

To the dismay of some other European countries, British authorities have in 1986 licensed a new/large, high-sulfur-coal-fired unit in North Yorkshire without requiring SO_2 emission control (30).

IMPACT OF WEST GERMAN NO_x REGULATIONS

After enactment of 1983 landmark SO_2 legislation, which imposed modest NO_x requirements, concern about NO_x as a contributor to forest damage substantially increased. Following a "technology forcing" provision of the 1983 law tied to state-of-the-art technical developments, a 1984 accord among federal and provincial environmental ministers in effect substantially reduced the 1983 limits for NO_x. At the same time it called for deadlines to be set by the individual provincial jurisdictions. The limit values legislated in 1983 and tightened by sanction of the national government in 1984 for coal-fired boilers are shown in Table V (31). Note that existing coal-fired boilers (with future operation of unrestricted duration) as well as new boilers must limit NO_x emission to 200 mg/ sm^3, a level equivalent to approximately 100 ppm (volume). An approximate equivalence between the four most common emission concentration measures is: 1 mg/Nm^3 = 0.487 ppm = 0.35 g/GJ = 0.000814 lb/10^6 Btu (32). This stringent requirement is predicated on commercial experience in Japan indicating that selective catalytic reduction technology is effective, and the judgement that it is demonstrated to be capable of reducing emissions to this low level. [NO_x limits, 1984 basis, for new oil-fired units are 150 mg/Nm^3 above 110 MW(e) and 300 mg/Nm^3 from 18 to 110 MW(e).

For existing units of unspecified future lifetime the limits are 150 mg/Nm^3 above 110 MW(e) and 450 mg/Nm^3 from 18 to 110 MW(e)]. Note, however, that (at the option of boiler owners, as decided by them in 1984) old boilers aggregating approximately 12,000 MW(e) capacity will be phased out (i.e. retired) no later than 1993 after no more than 30,000 additional hours of operation, during which they will be allowed to emit 650 mg NO_2/Nm^3 (about 325 ppm); for wet bottom units above 18 MW(e), 1,300 mg/Nm^3 will be allowed; and for oil-fired units, 450 mg/Nm^3. The state government of Baden-Wuerttemberg, the area of greatest forest-damage severity, was the first to impose prompt deadlines for the stringent 1984 NO_x emission limits (33). Dry bottom boilers, both new and existing, must comply by 1988; and wet (molten-ash) bottom boilers, by 1990. Similar deadlines have also been established by other state jurisdictions including North Rhine-Westphalia. It is expected that the retrofitting of NO_x removal systems on existing West German boilers larger than 110 MW(e) will be completed by 1990 resulting in an average of 70% reduction in NO_x emissions.

The extremely stringent 200 mg/Nm^3 requirement for both new and existing coal-fired boilers larger than 110 MW(e) surpasses NO_x control requirements in all other nations including Japan (see Table VI) (34). The West German NO_x stringency for boilers above 110 MW(e) is all the more remarkable, taking into account that most NO_x emissions are from mobile sources. (Note that additional regulations are being considered in West Germany that will require lead-free fuel and catalytic converters for gasoline-fueled autos.) Influenced by West Germany, significant NO_x control legislation has also passed or is pending in Austria, Switzerland, The Netherlands, Denmark, Sweden, and the European Economic Community. Table VII (32) shows the NO_x emission management objectives of governing officials of the EEC, revised in 1985 to call for emission rates throughout Europe after 1995 comparable to current requirements in West Germany. New standards in Austria for coal-fired boilers above 110 MW(e) call for 150 mg/Nm^3 for new boilers, and commercially developed combustion modifications for NO_x control are expected to be routinely applied, primarily on dry-bottom boilers. However, the very substantial reduction that will be required from the uncontrolled NO_x emission levels illustrated by Table VIII (31) is resulting in widespread application of selective catalytic reduction to essentially all German boilers larger than 110 MW(e). Moreover, since it is necessary to sustain ample boiler temperatures in wet bottom boilers sufficient to maintain bottom ash in a molten state, only minor reduction in NO_x emission can be achieved by combustion modification; and wet bottom boilers will require SCR removal efficiencies as high as 90%.

New federal regulations issued on February 27, 1986 (3), limit NO_x emissions from industrial plants with an output of more than 5 kg NO_2/h, generally to a limit of 500 mg/Nm^3. (As noted above, the SO_2 emission limit for industrial plants with an SO_2 output of more than 5 kg/h has been set at a nominal level of 500 mg/Nm^3.)

Other new NO_x limits as of February 1986 are:

o Solids incineration, less than 50 MW(t); i.e., 18 MW(e)	
- Wood	50 mg/Nm^3
- Fluidized Bed:	
Above 20 MW(t)	300 mg/Nm^3
Other	500 mg/Nm^3
o Oil incineration, less than 50 MW(t)	250 mg/Nm^3
o Gas incineration, less than 100 MW(t)	200 mg/Nm^3
o Gas engines	
- Diesel	
Above 3 MW(t)	2,000 mg/Nm^3
Below 3 MW(t)	4,000 mg/Nm^3
- Otto	
Four-stroke	500 mg/Nm^3
Two-stroke	800 mg/Nm^3
o Gas Turbines	
Above 60,000 Nm^3/h exhaust	300 mg/Nm^3
Below 60,000 Nm^3/h	350 mg/Nm^3

OVERVIEW OF HIGH-EFFICIENCY NO_x REMOVAL ACTIVITY

The emission limit (200 mg/Nm^3) derived in 1984 for boilers above 110 MW(e) is well beyond the capabilities of combustion modification techniques and requires the use of flue gas cleaning techniques for NO_x removal such as selective catalytic reduction (SCR) and wet or dry sorption. With the resulting requirement for NO_x reductions in the amount of 50-70% or more, postcombustion flue gas treatment can be expected to find broad application in Europe, especially processes that are capable of removing both SO_2 and NO_x (and possibly particulates), and that can function adequately in power plant service. However, because of the early (late-1980s) deadlines for compliance in West Germany, and despite the fact that it serves only to remove NO_x, the highly developed SCR process is being most broadly assessed and applied.

Although SCR has extensive commercial experience in Japan, enough differences exist in potential German application to warrant substantial pilot-scale SCR testing. The concerns include (1) a more variable load pattern or more frequent load swings, which may cause thermal shock to the catalyst structure; (2) possible fly ash effects due to the differences in Japanese and German coals; and (3) ammonia slippage problems due to the higher NO_x removal requirements in Germany.

To date over 50 SCR pilot plant trains have been installed and tested (35) to assess performance and characteristics. Optimism in SCR performance is reflected by the increase in catalyst life guarantees by vendors from 1 year in 1984 to 2 years or more currently.

Some areas, such as Baden-Wuerttemburg (with heavy forest damage) and Rhine-Westphalia (a large NO_x-emitting area), have more advanced

programs in NO_x control planning and therefore account for most NO_x control installations to date. In Baden-Wuerttemburg, 3700 MW(e) of SCR will be in place by 1990. For retrofits, several will be supplied downstream of FGD due to inadequate plot space.

Of 10 competing SCR system suppliers in Germany, 6 are licensees of Japanese processes and 3 offer German developments including use of activated carbon, ceramic molecular sieve, and iron oxide. An American licensor, Norton, uses a zeolite catalyst. The first major SCR facility has been installed on a 460 MW(e) bituminous-coal-fired, dry bottom boiler and commenced operation in early 1986. Another early installation of 160 MW(e) capacity on a bituminous-coal-fired, wet bottom boiler will achieve close to 90% NO_x removal.

Other potentially important developments for NO_x removal include sustained pilot and field test programs seeking to adapt the rotary regenerative air preheater to incorporate catalyst-coated plates, permitting it to also serve as an SCR reactor. Catalyst temperature in this integrated arrangement for highdust service ranges from 150°C to less than 350°C (302°F to less than 662°F), whereas an SCR reactor typically positioned upstream of the air preheater operates at approximately 350°C (662°F).

For cold-side (tail-end) SCR service (downstream of FGD) activated coke is of considerable interest since its catalysis is effective at a comparatively low temperature, 90-120°C (194-248°F), and requires less reheating of the water-saturated gas prior to the SCR step.

For bituminous dry-bottom service, the Japanese-devised, advanced low-NO_x technique, called "In Furnace NO_x Reduction" or "Fuel Staging" or also "Reburning Technology" holds great long-term promise. It is believed to have the potential to decrease the NO_x level below that with other burner technologies by 30-50%. A secondary fuel is injected into the furnace above the main burners, and the remaining air for burnout is supplied through ports above the secondary fuel injection. The secondary fuel will considerably reduce the NO produced in the main combustion zone to yield N_2. The fuel staging technique is not commercially demonstrated in coal service and is faced with a number of problems connected with burnout, corrosion, and slagging (36). The injection of secondary fuel leads to a high concentration of hydrocarbon radicals in a zone of high temperature and air deficiency. To a great extent these radicals reduce the NO molecules produced in the main combustion zone to N_2 (direct NO reduction) or reduced nitrogen compounds. This complex process includes both gas-phase reactions and heterogeneous gas/solid reactions. By supplying the balance of combustion air, combustion in the furnace is completed in the burnout zone. In this zone the nitrogen compounds formed as intermediate products in the reduction zone are further converted, partly to N_2 (indirect NO reduction) and also back to NO. Tests have shown that by this process a net reduction of NO_x by about 50% can be achieved. The development of firing systems using the IFNR principle by staged fuel supply in the furnace chamber is being actively pursued by a number of companies and institutions

in Japan, Germany, and the U.S. Full-scale experience has been gained with oil-firing systems. As to its application to coal-firing systems, first test results have up to now only been obtained in pilot-scale plants. Development has been started on injecting the secondary fuel into a burner-related arrangement; i.e., achievement of staged fuel supply to the individual coal flame.

Many pilot plants have been installed in West Germany to investigate use of wet simultaneous SO_2/NO_x removal systems, both of the absorption/reduction and oxidation/absorption types. Wet NO_x removal techniques include a usable-gypsum producing process previously described that is reported to use a ferrous complex ion (FeEDTA) in conjunction with sulfite (and thiosulfite) ions to fix and chemically reduce flue gas NO. A 750 MW(e) absorption/reduction process installation will start up in 1987. Although the simultaneous wet processes are seen to have possible economic advantages, the tight deadlines (compliance as early as 1988) are leading to heavy use of the more commercially established SCR techniques.

Brown coal (lignite) fired power plants (34), constituting approximately 30% of electric production in West Germany, present unique problems for NO_x emission control because of special firing arrangements required and because of the high water vapor content of the flue gas. Special pilot plant and field tests of control methods have been underway for several years.

COMBUSTION CONTROLS FOR NO_x EMISSION REDUCTION

Historically, combustion modifications have been the commercially available means of controlling NO_x emissions at coal-fired utility boilers. For reasons of cost-effectiveness and reliability, combustion controls offering significant NO_x reductions are likely to continue to be the preferred NO_x control approach for both new and retrofit applications. In general, the most viable near-term and cost-effective retrofit combustion control options are low excess air firing, overfire air, and low-NO_x burners.

Among these options, low-NO_x burners promise the greatest potential for significant (50-60%) NO_x reductions and are thus receiving substantial development attention. Specifically, these burners are designed to control the mixing and stoichiometry of fuel and air in the near-burner region of the furnace to retard conversion of fuel-bound nitrogen to NO_x while still maintaining high combustion efficiency. This is accomplished by controlling the momentum, direction, and quantity of fuel and air streams at the burner throat as they are injected into the furnace chamber.

Few existing coal-fired utility boilers have yet been retrofitted with low-NO_x combustion systems. Retrofitting combustion controls to existing units appears to be technically feasible, given sufficient attention to site-specific design and engineering. These advanced systems pose new combustion conditions (furnace flow and mixing requirements and boiler

control issues) significantly different from those of conventional burners. Their ultimate success hinges on the ability to integrate these processes with the fixed physical and thermodynamic constraints of any existing boiler. In order to expand the retrofit applicability of these low-NO_x systems, several demonstrations are being carried out on a variety of boilers.

Independently, advanced NO_x combustion control concepts are being developed to more closely control the fuel/air mixing, temperature, and combustion chemistry in the furnace. Reburning technology originated in Japan is under development to destroy NO_x already formed in the initial combustion step. As noted above, reburning has been reported to produce a 50% further reduction beyond that of low-NO_x burners.

Wet bottom (i.e., slag tap boilers) are limited in their ability to apply combustion modifications for NO_x control since generally lower gas temperatures brought about in at least a portion of the furnace would be expected to alter the wet slag properties and hinder its drainage from the bottom of the boiler. New boilers in West Germany equipped with recently developed low-NO_x burners emit 800 mg NO_2/m^3 in the case of dry bottom design and 1,300 mg NO_2/m^3 in the case of wet bottom design (31). In one of the most recent applications to dry-bottom service, low-NO_x burners are being used in conjunction with application of over-fire air to try to achieve an emission rate of 650 mg NO_2/m^3. It is expected that in-furnace NO_x reduction (reburning) will soon be applied to some pulverized-coal-fired boilers after further current operation of this furnace-staging method on a 40 MW(e) gas-fired boiler. In conjunction with flue gas recirculation an emission rate of 100 mg NO_2/m^3 can be ultimately foreseen.

APPLICATION OF COMMERCIAL SCR SYSTEMS

General

The SCR process is based on treating the flue gas with ammonia (NH_3) in accordance with the following chemical reactions:

$$4NO + 4NH_3 + O_2 \text{ - - -> } 4N_2 + 6H_2O \quad (1)$$
$$2NO_2 + 4NH_3 + O_2 \text{ - -> } 3N_2 + 6H_2O \quad (2)$$

The reaction proceeds when the gas temperature is from 800 to 1000°C (1470 to 1830°F), which is the basis for the selective noncatalytic reduction method. However, in the presence of a suitable catalyst, the reaction proceeds with a gas temperature of 300-400°C (570-750°F), which is close to the temperature of the flue gas as it exits the boiler economizer section upstream of the air preheater. This is the basis for the utility SCR process, which is theoretically capable of achieving 85-95% NO_x removal for ammonia injections of 0.85 to 1 mole NH_3 per mole of NO present.

Commercial Applications in West Germany

No significant amount of commercial operating time has yet been achieved in Europe, but many utility installations are in initial operation or under construction in West Germany. Sale of SCR systems in West Germany for initial startup during the period 1986-1988, publicized to date (37), are as shown in Table IX.

By 1990, 3700 MW(e) of NO_x removal systems, primarily SCR, will be installed in Baden-Wuerttemberg. Approximately 30,000 MW(e) of large boiler capacity in North Rhine-Westphalia will be so equipped by 1989 or 1990. In all, the boiler NO_x emission inventory throughout West Germany will ultimately be reduced by 0.7×10^6 metric tons, principally by SCR (38).

Based on extensive economic assessments recently published (21) retrofit capital investment for a typical 700 MW(e) high-dust SCR installation for dry bottom boilers is reported to be 32.4 million DM; i.e., 46 DM per kW. Annual cost with 6000 hours/year of operation and 3-years catalyst life is 18.4 million DM including fixed cost of 6.0 million DM (representing 18.5% of the capital investment of 32.4 million DM). On a unit basis this annual cost equals 0.44 Pfg per kWh. Values are based on 1985 currency.* It is believed that individual applications may be significantly higher in capital cost (and in operating cost when economics are based on substantially less than 3 years catalyst life).

Earlier Japanese Activity

In the work in Japan leading up to present applications in Germany the process manufacturers have routinely designed the SCR reactor for 80% NO_x removal and have often designed for 90% removal with a guarantee of 80%. The catalysts are also warranted for 1 to 2 years of lifetime. The predominant catalyst that has been applied in Japan (33), and that is now being most extensively used in Germany, is ceramic based and contains TiO_2, V_2O_5, and traces of heavy metals. Each of a multitude of catalyst layers that the flue gas contacts consists of single blocks of either honeycomb shaped ceramics or catalyst covered plates. Operational problems that have previously been encountered and addressed in commercialization of the technology in Japan are:

- Plant efficiency reduction due to economizer tube removal
- Catalyst erosion (and poisoning in the earlier installations)
- SCR reactor plugging with ash
- Plugging of the air preheater and induced draft fans with dust and ammonium bisulfate
- Ammonia bypass leakage with a resulting contamination of the fly ash and the FGD wastewater
- Maintenance and accuracy of the NO_x and NH_3 instrumentation.

*Based on 1 DM = U.S. $0.50, 1 Pfg per kWh = 5 mills per kWh.

Stringent Removal-Efficiency Requirements

While Japanese practice has established 80% NO_x removal in SCR as a generally practical maximum level to avoid significant ammonia leakage to the downstream air preheater and FGD system, licensing by some German provincial authorities calls for close to 90% SCR efficiency in specific applications (which is of concern in view of the Japanese experience). This includes a small installation of VEBA Kraftwerke at Knepper, 1986 initial startup, on a wet bottom boiler to reduce NO_x emissions to 200 mg/m^3. An SCR system starting up in 1986 on a dry-bottom boiler is at Neckarwerke in Altbach, approximately 370 MW(e), which will also achieve a 200 mg/m^3 NO_2 emission, but at a substantially lower removal efficiency.

Air Preheater Fouling

Through prior field study in Japan and more recent work in Germany (39), major efforts have been made to establish air preheater design criteria to make it compatible with common SCR operation upstream of the air preheater. In reducing flue-gas stream temperatures to as low as 150-230°C (300-450°F), the air preheater causes excess NH_3 vapor from the SCR operation to react with water vapor and most of the SO_3 gas present to form ammonium bisulfate and ammonium sulfate. (The SCR reactor further enhances this formation because the SCR catalyst converts approximately 1% of the flue gas SO_2 to SO_3, thereby essentially doubling the flue-gas SO_3 concentration.) Ammonium sulfate vapor solidifies below 250°C (482°F), and ammonium bisulfate forms a liquid at a somewhat lower temperature. The latter solidifies at approximately 150°C (300°F). These compounds stick to fly ash and to the internal surfaces of the air preheater. It has also been found that the air preheater heating surfaces, so wetted and fouled, act like "fly paper" in collecting fly ash particles from the flue gas, further contributing to internal deposits causing increased gas pressure drop. Fouling can be expected to be encountered when NH_3 concentration in flue gas downstream of SCR is as high as approximately 5 ppm. This can be expected when SCR is operated at NO_x removal efficiency substantially higher than 80% or even at lower efficiencies when, toward the end of the usable life of the catalyst charge, increased ammonia feed is used to maintain required NO_x removal efficiency. Nonetheless, the Germans emphasize that SO_3 content is a critical factor; at a specified NH_3 leakage rate it is the SO_3 content which determines whether there will be a serious rate of buildup of dry ammonium sulfate with liquid ammonium bisulfate on the air preheater heating surfaces. Based on field test experience in both Japan and Germany important criteria have been established for design of de-NO_x-compatible air preheaters (and gas-gas heaters for cold-side SCR):

- The heating surfaces must have a configuration that is easily cleaned by soot blowing.
- The crossover of heating-element layers must be avoided in the area most likely to be affected by ammonium bisulfate deposition.

- o Enameled heating elements should be used, particularly when SO_3 concentration is greater than 2 ppm.

- o Highly efficient sootblowing devices must be used in order to limit outages.

- o When SO_3 concentration is greater than 2 ppm need of provision for frequent off-line water washing to the air preheater must be anticipated; unlike rotary regenerative heat exchangers used to achieve flue gas reheat downstream of wet FGD, air preheaters downstream of SCR cannot be water washed on-line.

Cold-Side SCR

In Japanese and European programs to retrofit SCR systems for flue-gas NO_x removal, physical plot-space limitations have in some instances prevented the tying in of the SCR reactor at the normal location, upstream of the air preheater; i.e., in high-dust service at the "hot side" of FGD. In such instances it may be necessary to use a "cold side" (i.e., tail end) installation, adding SCR downstream of FGD, but connected so as to receive the FGD outlet gas after it has been heated to a suitable temperature [i.e., approximately 320°C (608°F)] for the chemical reduction of flue-gas NO_x.

The largest existing FGD-cold-side SCR operation (downstream of wet FGD) is a 1.32×10^6 Nm^3/hr (820,000 scfm) 1979 installation, the equivalent of 330 MW(e), at an iron ore sinter furnace of Nippan Kokan KK at its Keihin Works in Japan. It utilizes a rotary regenerative heater followed by ammonia injection and an iron ore catalyst reactor operating at 390°C (734°F), to reduce a 200 ppm flue gas NO_x concentration to 30 ppm. The 1979 capital cost of the system installation is understood to be 6.7 billion yen, approximately 15 million DM, which is equivalent to approximately 20 million DM (1985), or roughly 60 DM per kW, higher than for a typical hot-side application. Cold-side installations in West Germany announced to date (37) are all small capacity with generally poor economies of scale. A municipal power plant, which is installing three 35 MW(e) cold-side SCR systems utilizing cyclical operation of twin granular heat-exchange beds in conjunction with feed of ammonia to a single catalyst chamber operating at 350°C (662°F) to reduce NO_x emission to 200 mg/Nm^3, is projected to have a capital cost of 250 DM per kW (and a unit cost of 2.5 Pfg per kWh) (40). In a new boiler application of SCR, the greater simplicity and economy of a hot-side installation would be generally expected to probably rule out use of a cold-side design. However, the very substantial difference in total cost between hot- and cold-side retrofit installations, typically, has largely to do with energy costs of the cold-side technique that lead to substantial reheating of the flue gas above the water saturated temperature at which it exits the upstream FGD system. When an appropriate credit for reheat is given, the margin of cost difference between hot- and cold-side designs is significantly reduced. Cold-side SCR yields approximately 50°C (90°F) of flue gas reheat, and thus eliminates need for reheat facilities that would normally be included in the FGD installation. In

addition, catalyst life and system reliability are expected to be better with cold-side operation. In an extensive field pilot test program (39) that began in early 1985 favorable reliability for tail-end system installations has been verified. No gas pressure drop increase has been experienced; SO_3 content of the flue gas is below 2 ppm. NH_3 leakage is approximately 5-10 ppm, and the flue-gas dust content is less than 50 mg/Nm^3 (0.04 lb/10^6 Btu).

Development of Integrated Air Preheater/SCR-Reactor Design

To minimize the cost penalties for installing and operating cold-side SCR at large coal-fired electric utility plants when plot-space limitations make it necessary to do so, system designs are anticipated that combine the regenerative heat exchanger and the SCR reactor into a single integrated assembly with a capital cost of approximately 150 DM/kW ($80/kW) and a total cost of approximately 1.5 Pfg/kWh ($0.008/kWh). Engineering and operation of such future integrated system designs are expected to include use of economical coal-based high-pressure steam (in lieu of fired clean fuel) for the augmenting of flue-gas feed preheat upstream of SCR, and the advantageous use of a plate rather than honeycomb-grid catalyst configuration.

Air preheater suppliers in Germany have extensive field programs underway to develop an attractive SCR system design, (39) the De-NO_x air preheater (or a De-NO_x Gas-Gas-Heater), for moderate NO_x removal efficiencies in either hotor cold-side service. Since the regenerative heat exchangers have a surface area comparable in size to that of a typical SCR reactor, the basic idea of the development is to integrate the catalyst into the heating surface of the already available Lungstrom air preheater and thereby avoid need for cost and space of a separate SCR reactor. The supplier is concentrating on the optimum utilization of the element height despite the axial temperature variation in the basket; and he expects efficient operation of the systems after the initial "teething" problems have been solved. Despite NO_x removal efficiencies of 60% and higher in small scale field tests, an initial large scale, 150 MW(e), test in late 1985 demonstrated far less. Further extensive small scale testing is underway in this major developmental program seeking to overcome present obstacles.

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TABLE I. FEDERAL SO_2 CONTROL REQUIREMENTS FOR WEST GERMAN COAL-FIRED BOILERS

Size, MW(e)	SO_2 Emission Limit mg/Nm^3 ($lb/10^6$ Btu)	% Removal	Compliance Deadline	Approx. No. Boilers Existing
Over 110	400 (0.5, Avg.)	85	07/01/88	160
35 to 110	2,000 (2.5, Avg.)	60	04/01/93	370
18 to 35	2,000 (2.5, Avg.)	--	04/01/93	300

TABLE II. POPULATION OF EXISTING WEST GERMAN COAL- AND OIL-FIRED BOILERS

Size, MW(e)	Number	Aggregate MW(e)	Average MW(e)
Above 300	41	18,400	450
135-300	91	17,800	195
75-135	95	9,900	104
30-75	378	18,500	49
9-30	548	10,600	19
Above 9 (Total)	1153	75,200	—

TABLE III. PRINCIPAL LIME/LIMESTONE SYSTEMS APPLIED

Process	Approx. Aggregate MW(e)	Approx. No. of Install.
Deutsche Babcock	11,000	30
Mitsubishi/Thyssen	5,000	15
Chemico-Mitsui/Steinmueller (GEESI)	7,000	15
Research Cottrell Double-Loop	4,000	10
Saarberg-Hoelter-Lurgi Buffered Limestone	6,000	25
Bischoff Single-Loop	4,000	20
Total	37,000	115

TABLE IV. FORECAST OF WEST GERMAN FGD GYPSUM USE

Market	% Replacement of Natural Materials	Consumption, 10^6 metric ton/yr
Plaster, wallboard	Close to 100	2.5 to 3
Floor underlayment	50	0.6 to 1
Portland cement	100	0.5 to 0.6
Mining mortar	50	0.6 to 0.7
Gypsum/wood chipboard	15	0.5 to 0.6
Total		5.3 (Approx.)

TABLE V. NO_x CONTROL REQUIREMENTS FOR WEST GERMAN COAL-FIRED BOILERS

Category	NO_x Emission Limit, mg NO_2/Nm^3* (ppm), (6% O_2 Basis, Dry Bottom: 5% O_2 Basis, Wet Bottom)	
Size, MW(e)	18 to 110	Over 110
New Units, Dry Bottom:		
1983	800 (400)	800 (400)
1984	400 (200)	200 (100)
New Units, Wet Bottom (Slag-Tap):		
1983	1,800 (900)	1,800 (900)
1984	400 (200)	200 (100)
Existing Units, Dry Bottom:		
1983	1,300 (650)	1,300 (650)
1984	650 (325)	200 (100)
Existing Units, Wet Bottom (Slag-Tap):		
1983	2,000 (1,000)	2,000 (1,000)
1984	1,300 (650)	200 (100)

*200 mg/Nm^3 equals approximately 0.16 $lb/10^6$ Btu

TABLE VI. COMPARISON OF NO_x EMISSION STANDARDS FOR COAL-FIRED UTILITY BOILERS

	NO_x Emission Standard, mg NO_2/Nm^3 (6% O_2)
West Germany, New and Existing over 110 MW(e), (1/2 hr avg)	200
U.S., New Sources	600-750
Japan, after 1987	410

300 mg/Nm^3 for existing boilers (29).

TABLE VII. EFFECT OF AMENDED EUROPEAN COMMUNITY DIRECTIVE

			Emission Limits, mg NO_2/Nm^3		
			Coal	Oil	Gas
1983 Proposed Directive					
All Plants over 50 MW(e)*					
to 1995			800**	450	350
after 1995			400***	220	180
1985 Amended Directive					
to 1995:	over	50 MW(t)		450	350
		50-100 MW(t)	800**		
		100-300 MW(t)	800		
	over	300 MW(t)	650		
after 1995:	over	50 MW(t)		150	100
		50-100 MW(t)	400***		
	over	100 MW(t)	200		

Source: Amended proposal for a Council Directive on Limitation of Pollutants from Large Combustion Plants. COM(85)47 final. Brussels: European Commission, February 1985.

*100 MW(t) equals approximately 37 MW(e)
**1300 mg/Nm^3 for slag tap furnaces
***800 mg/Nm^3 for slag tap furnaces

TABLE VIII. TYPICAL PRECONTROL BOILER NO_x EMISSIONS

Type Boiler	Actual Emission, mg NO_2/Nm^3 (6% O_2)	
Bituminous, Wet Bottom	800 - 2,800	1,700
Bituminous, Dry Bottom	800 - 1,500	1,200
Lignite, Tangentially Fired	400 - 700	500

TABLE IX. PRINCIPAL SCR TECHNOLOGY SUPPLIERS

Catalyst Licensor	Approx. Aggregate, MW(e)	Number of Installations	
		High Dust	Cold End
Kawasaki	2,200	4	2
Mitsubishi	1,500	5	-
IHI	900	4	1
Babcock Hitachi	1,000	4	-
Norton	105	-	3